Table 4.1 Comparison of SCC types (NEB 1996; CEPA 1997)

Factor	Near-neutral pH SCC	High pH SCC (Classical)
Location	• Associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings	• Typically within 20 km downstream of pump or compressor station • Number of failures falls markedly with increased distance from compressor/pump and lower pipe temperature
Temperature	• No apparent correlation with temperature of pipe • May occur more frequently in the colder climates where CO_2 concentration in groundwater is higher	• Growth rate increases exponentially with temperature increase
Associated Electrolyte	• Dilute bicarbonate solution with a neutral pH in the range of 5.5 to 7.5	• Concentrated carbonate-bicarbonate solution with an alkaline pH greater than 9.3
Electrochemical Potential	• –760 to –790 mV ($Cu/CuSO_4$) • Cathodic protection does not reach pipe surface at SCC sites	• –600 to –750 mV ($Cu/CuSO_4$) • Cathodic protection contributes to achieving these potentials
Crack Path and Morphology	• Primarily transgranular (across the steel grains) • Wide cracks with evidence of substantial corrosion of crack side wall	• Primarily intergranular (between the steel grains) • Narrow tight cracks with almost no evidence of secondary corrosion of crack wall

4.2.4 Crack Growth

The cycle of SCC crack growth is normally modeled as a four-stage process as shown in Figure 4-5. The first stage is the development of conditions conducive to SCC and is followed by the crack "initiation" stage. These cracks then continue to grow and coalesce, while additional crack initiation also occurs during stage 3. Finally, in stage 4, large cracks coalesce and failure occurs. Appendix A discusses the background and research of the crack growth rate in more detail.

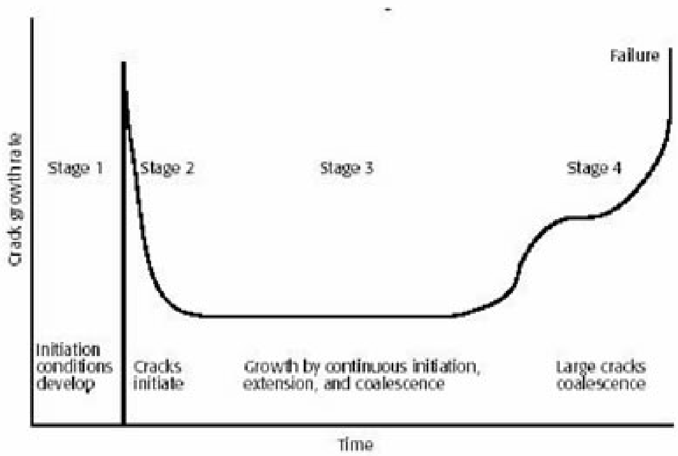

Figure 4-5 Four Stage Process of SCC Growth

While a single crack might grow large enough to cause a leak, coalescence typically is necessary for the defect to grow long enough to cause a rupture. If cracks form close to one another, crack growth may be dominated by coalescence into collinear cracks and can occur throughout the SCC life cycle. A combination of environmental and mechanical forces can cause cracks to grow. In the final stage of growth, after cracks have coalesced sufficiently for tearing to begin, the environment no longer plays a role. In some cases, tearing is preceded by a stage of crack growth in which fatigue is the dominant crack propagation mechanism.

The geometry of the crack colonies resulting from near neutral-pH SCC is important in determining whether the cracks coalesce and grow to failure (NEB 1996). Colonies of cracks that are long in the longitudinal direction yet narrow in the circumferential direction are a greater risk to pipeline integrity than colonies of cracks that are shorter in the longitudinal direction and wide in the circumferential direction. The individual cracks in long, narrow colonies are oriented head to tail and tend to link together, leading to rupture. However, for colonies that are about as long as they are wide, growth occurs mainly near the edges. Cracks located deeper within these colonies with circumferential spacing less than 20 percent of the wall thickness are generally shielded from stress and become dormant (NACE 2003).

4.3 History of SCC in Pipelines

The first documented case of SCC causing a pipeline failure was the Natchitoches, Louisiana, incident in the mid 1960s. This rupture was caused by high-pH SCC and resulted in a gas release, explosion and fire resulting in several fatalities. Spurred by this discovery, research on high-pH SCC in pipelines has been ongoing since that time. In the late 1960s, a concentrated carbonate-bicarbonate solution was identified as the most likely environment for SCC and evidence of this solution at the pipe surface was found in a limited number of cases (Fessler 1969).

Near neutral-pH SCC in pipelines was not identified until 1977. According to the *Stress Corrosion Cracking Study*: "Since 1977, SCC has caused 22 pipeline failures in Canada on both natural gas and liquid pipeline system[s]. Failures include 12 ruptures and 10 leaks. Most of the SCC-related failures occurred on pipelines coated with polyurethane tape and were installed between 1968 and 1973 with most of the reported failures occurred between 1985 and 1996." (Hall and McMahon 1999).

4.3.1 Canada/International (NEB 1996)

In the Introduction to *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* the NEB notes: "Our awareness of SCC on the Canadian pipelines we regulate began in 1985. TransCanada had three failures on the Northern Ontario portion of the pipeline between March 1985 and March 1986… These failures were attributed to stress corrosion cracking and were considered at the time to be the first evidence of SCC in Canada, although subsequently it was determined that SCC had been detected on other pipelines in the 1970s. The type of SCC which caused these failures was different from the 'high-pH' SCC that had been found on other pipelines in the world." (NEB 1996).

The NEB of Canada conducted an inquiry into SCC on pipelines in 1993, concluding that the situation was being managed appropriately. However, ruptures on the TransCanada Pipelines (TCPL) system in 1995 caused the NEB to reconsider SCC and begin a new inquiry. The result was a series of 27 recommendations to promote public safety as described in *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* (NEB 1996). Each pipeline company under NEB jurisdiction was required to develop and begin maintenance of an SCC integrity management program by June 1997, and additional research was to be conducted on SCC.

4.3.2 United States

Until recently, the United States concentrated on high-pH SCC. Recent failures, however, have been attributed to near neutral-pH SCC. No specific regulations pertaining to either design or operational assessment for SCC detection or control in pipelines existed in the United States until recently. With the publication of ASME B31.8S in 2002, *Managing System Integrity of Gas Pipelines*, which was incorporated by reference into Title 49 Code of Federal Regulations (CFR) Part 192 (49 CFR 192), there is now some guidance regarding high-pH SCC, at least for gas pipelines. Liquid operators may choose to follow these guidelines as well, with the appropriate modifications because codes for liquid pipelines do not currently address SCC in this detail. ASME B31.8S describes risk assessment procedures and outlines inspection and examination procedures for SCC, although it does not supply analytical or theoretical guidance for high-pH or near neutral-pH SCC threat assessment . Development of other guidance documents is currently ongoing; in particular, NACE International is writing a Direct Assessment Recommended Practice for SCC, which may be published before end of 2004. This is discussed further in Chapter 6 and Chapter 8 of this report.

4.4 *Contributing Factors to SCC in Pipelines*

4.4.1 Metallurgy

Metallurgy can affect SCC through composition and microstructure. However, pipeline steels, and certainly the conventional steels that have historically been used in the last 50 years, do not contain elements found in similar carbon-manganese steels used in literally hundreds of construction applications without reports of SCC.

More recently, the yield strength of linepipe has gradually increased by the addition of micro-alloying elements such as vanadium, columbium and/or titanium. The addition of these elements tends to produce a finer grain in the microstructure, increasing both strength and toughness. Controlled rolling and cooling of the steel plate used to manufacture pipe has resulted in finer grained bainite steel microstructures.

A number of research investigations involving small-scale, laboratory-reproduced SCC and using both high- and low-pH environments have been conducted without achieving a meaningful correlation between steel chemistry and susceptibility to SCC. Danielson and Jones (2001) discuss the high-pH SCC testing of six different heats of X52, as well as three heats (X65, X70, X80) of modern steels. Their paper concludes: "In general, the microstructure/microchemistry had a small effect on the SCC behavior."

Nevertheless, certain batches of pipeline steel have been found to be much more susceptible to SCC than other batches with similar compositions and microstructures (Beavers and Harper 2004). A full understanding of this remains to be developed, but current research suggests that other characteristics of the steel, such as creep response to cyclic loading, may be important.

4.4.2 Manufacturing

Line pipe is manufactured using one of four processes: seamless pipe, electric resistance welded pipe made from steel coils, flash welded pipe from plate, and submerged arc-welded pipe made from steel plate. The vast majority of line pipe for gas transmission service is produced by one of the three seam welded processes. Pipe in grades X60 and higher achieves some of its strength from the controlled rolling procedures used to reduce the thickness of the original cast slabs to the final pipe wall thickness. These procedures include not only the hot work but also the cooling rate of the plate or strip after hot rolling. The microstructure may contain varying amounts of ferrite, pearlite and bainite with wide variation in the crystalline grain size. There is no strong evidence that any of the items above either promote or inhibit SCC.

The first reported cases of SCC exhibited intergranular cracking (high-pH SCC) in steels with a microstructure that consisted of grains of low-carbon ferrite and higher carbon colonies of pearlite. Typically, the more recently detected near neutral-pH SCC has occurred on slightly higher yield strength steels with a much finer grain size and a higher toughness. However, there are a number of cases of near neutral-pH SCC in older, large grained, low-strength steel and cases of high-pH SCC in newer, fine-grained steel. Thus, regarding reported cases of SCC, no generalizations regarding metallurgy can be made.

4.4.3 Mechanical Properties

The mechanical properties of highest interest for most gas transmission piping are the yield strength and the toughness. Generally, the best economics result from selecting the highest strength pipe material available for the design of a new pipeline system. As improved manufacturing procedures are being developed, higher grades of pipe is being purchased. There is no strong evidence that increasing strengths up to and through grade X70 increases susceptibility to SCC initiation or growth.

Increases in toughness, which have occurred in parallel with strength, have significantly increased the critical size of the crack necessary to produce ruptures. The use of toughness values in engineering evaluations of critical flaw sizes is discussed further in Sections 8.2.5 and 8.2.6.

4.4.4 Pipeline Operating Conditions

As previously discussed, SCC requires three conditions to be satisfied simultaneously: 1) a tensile stress above the threshold stress, 2) an appropriate environment at the steel surface, and 3) a susceptible material.

Below some value of tensile stress, referred to as the threshold stress, crack initiation does not occur. The threshold stress is difficult to accurately define but, depending on the range of stress fluctuation, is on the order of 40 to 100 percent of the yield strength for classical SCC. A threshold stress for near neutral-pH SCC has not been established (Beavers 1999).

The operator has at least some control of the applied tensile stress when it is strictly the result of internal pressure in the system. Unfortunately, residual tensile stresses from manufacture, bending stresses from pipe movement, overburden loads from soil, dents or gouges, or from heavy equipment can cause as much or more tensile stress as that caused by internal pressure, all of which is beyond the control of the operator.

Note that in Canada some 10 to 20 percent of the SCC reported is oriented in a circumferential direction, i.e., the dominant stress affecting the crack is oriented axially to cause crack growth (CEPA 1997). The direct longitudinal stress caused by pressure can be up to half of the hoop stress. However, pipe flexure will result in additional stress, and the resultant value can exceed the hoop stress, with the maximum/minimum values at the extreme fibers of bending. The C-SCC cases reported by CEPA are associated with undulating terrain where pipe loading resulted from soil creep or localized bending. Localized bending may also occur at dents resulting in higher axial stresses in the local region.

Pipe that has been cycled into the plastic range multiple times sometimes may experience a condition known as cyclic softening. This appears as a loss of yield strength and can significantly reduce the threshold stress. Again, the operator has little control over cyclic softening.

In addition, the operator has little control over the pH of the groundwater and is unable to control the aggressiveness of the environment, except for new construction by installing a premium coating system. Unfortunately, these coating systems may not be considered suitable for recoating in the ditch. Note also that the pH of the groundwater will be modified by the electrochemical reaction at the pipe surface.

The operator does have some control over the operating temperature. For example, some operators have installed cooling towers to help control SCC.

4.4.5 Coating

Coating type and condition (sometimes a function of the installation procedure, associated quality control or lack thereof, and weather conditions at the time of installation) have a profound effect on SCC. This is especially true when the coating has a tendency to disbond (i.e. the coating comes away from the pipe but does not break), or forms holidays (i.e., breaks or gaps in the coating). This is true for tape coatings, such as the polyethylene-backed tapes used predominantly in the early 1960s to 1980s. These tapes are spirally wrapped around the pipe with an overlap at the helix line. "Tenting" occurs between the pipe surface and the tape along the ridge created by longitudinal, spiral, and girth welds. Tenting also occurs at the overlap between the helix of the wrap.

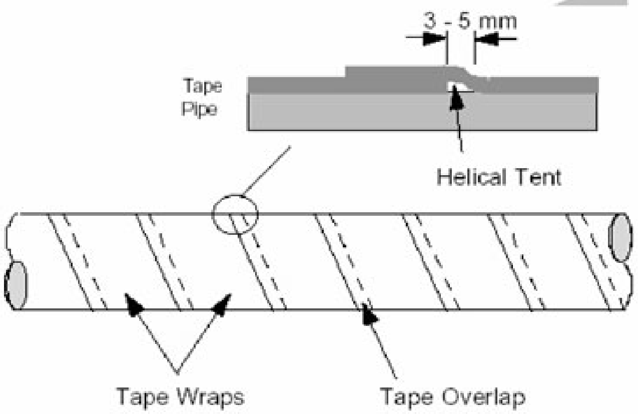

Figure 4-6 Polyethylene Tape Helical Tent (CEPA 1997)

When the tape disbonds from the pipe, moisture can accumulate beneath the tape surface. The tape itself has fairly high electrical insulation properties, thus preventing cathodic current from reaching entrapped moisture beneath the tape at the pipe surface. In Canada, about three-quarters of reported near neutral-pH SCC-related service incidents have occurred under these tape coatings. The cracks tend to occur at or near the toe of the seam weld where stress is concentrated and water has access, as well as where the coating has been damaged or disbonded (NEB 1996).

Asphalt and coal tar coatings are relatively thick and can be brittle. The coatings can disbond, especially due to poor surface preparation. Over time, the volatiles can disperse, leaving the coating relatively brittle. Unlike tape coatings, when these coatings disbond, they usually, but not always, become saturated with moisture and conduct cathodic current, thus protecting the pipe. If the coating is brittle, it may break into pieces, also allowing a path for the cathodic current protection. SCC might still occur when the soil is so resistive that the cathodic current cannot reach the pipe. For these coating types, there is no preferential location, but SCC might occur wherever disbondment or holidays occur (NEB 1996).

It is generally agreed that fusion-bonded epoxy (FBE) coatings, which are often the coating of choice for newly installed pipelines in the United States, are an effective protection against SCC. Extruded polyethylene, because the coating system is monolithic, also appears to be effective, except possibly at tape-wrapped girth welds.

4.4.6 Soil conditions

In 1973, Wenk described results of analyses of soil and water extracts (from the soil) taken from high-pH SCC locations (Wenk 1974). While supporting data were not provided, it was stated that SCC had occurred in a wide variety of soils, covering a range in color, texture, and pH. No single characteristic was found to be common to all of the soil samples. Similarly, the compositions of the water extracts did not show any more consistency than did the physical descriptions of the soils, according to Wenk. On several occasions, small quantities of electrolytes were found beneath disbonded coatings near locations at which stress corrosion cracks were detected. The principal components of the electrolytes were sodium carbonate and bicarbonate. Sodiumbicarbonate crystals were also found on pipe surfaces near some SCC colonies (Fessler 1973). Based on the presence of the sodium-based carbonates and bicarbonates, it is likely that these were high-pH SCC sites. Therefore, it is not surprising that these results are not consistent with the results of the TCPL studies performed in the 1980s and 1990s, when near neutral-pH SCC was found.

Mercer described the results of a field study conducted by British Gas Corporation in 1979 (Mercer 1979). Soil data from both the UK and U.S. were collected and analyzed. As in the study by Wenk, detailed information on the soil analyses was not provided, but it was concluded that soil chemistry had no obvious direct influence on high-pH SCC. The moisture content of the soil, the ability of the soil to cause coating damage, and localized variation in the level of CP were the primary soil-related factors identified.

Delanty and O'Beirne (Delanty and O'Beirne 1991, 1992) reported on the results of more than 450 investigative excavations performed on TCPL's system in the mid- to late-1980s. In the tape-coated portions of the system, near neutral-pH SCC was found in all of the various types of terrains and soils (e.g., muskeg, clay, silt, sand, and bedrock) present on the system. There was no apparent difference in the soil chemistry for the SCC and non-SCC sites. However, the SCC was predominantly located in imperfectly to poorly drained soils in which anaerobic and seasonally reducing environmental conditions were present.

In the same system, near neutral-pH SCC was found in the asphalt-coated portions of the system, predominantly (83 percent) in extremely dry terrains consisting of either sandy soils or a mixture of sand and bedrock. There was inadequate CP in these locations, based on pipe-to-soil potential measurements or pH measurements of electrolytes found beneath disbonded coatings. The remainder of the SCC sites on the asphalt-coated portions of the system had localized areas of inadequate CP, based on pH measurements of electrolytes.

Delanty and Marr developed an SCC severity rating model for near neutral-pH SCC for the tape-coated portions of TCPL's system in eastern Canada (Delanty and Marr 1992; Marr 1990). The predictors in that model were soil type, drainage, and topography. The soil classifications were based on method of deposition. The most aggressive soil types were lacustrine (formed by deposits in lakes), followed by organics over glaciofluvial (formed by deposits in streams fed by melting glaciers), and organics over lacustrine. The prevalence of SCC in glaciofluvial soils was about 13 percent of that in lacustrine soils, and about 17 percent of that in soils with organics over glaciofluvial or lacustrine. Very poorly or poorly drained soils were found to be the most aggressive, while level-depressed soil was found to be the most aggressive topography. The SCC model did not contain parameters associated with soil chemistry because the results of previous geochemical projects were inconclusive.

As described above, neither the early field studies conducted on high-pH SCC, nor the later field studies conducted on near neutral-pH SCC, detected a correlation between the occurrence of SCC and soil chemistry. On the other hand, high-pH SCC was not reported where the extensive field study of near neutral-pH SCC was performed in Northern Ontario (Delanty and O'Beirne 1991, 1992), suggesting that the soil conditions were not conducive to this form of cracking. Furthermore, no near neutral- or high-pH SCC was found in Northern Ontario where elevated pH electrolytes were detected, possibly because the soil conditions could not support the development of concentrated carbonate-bicarbonate solutions, even when the CP conditions were conducive to such development. These observations suggest that a further analysis of field soil data might provide insight into the role of soil/groundwater chemistry on the occurrence of SCC (Beavers and Garrity 2001).

Near neutral-pH SCC may be associated with local topographical depressions, e.g., at the base of hills or streams, where the groundwater either channels along the pipe or across it. Flowing water may help to maintain the near neutral-pH environment by supplying CO_2 to the electrolytic solution in a disbonded area. The majority of laboratory investigation has been performed in an NS4 electrolyte solution containing 5 percent CO_2. NS4 is a simulated trap water that is typical of liquids found beneath disbonded polyethylene tape coatings at locations where near neutral-pH SCC was found. Research shows that the crack growth rate increases with increasing CO_2 concentrations, and that the cracking becomes dormant in CO_2-free environments (Beavers et al. 2001).

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5 Prevention of an SCC Problem

5.1 Scope Statement

"Compile a report summarizing the history of SCC on pipelines, explaining the causes and factors contributing to SCC initiation and growth, and discussing methods for prevention, detection and mitigation of SCC on pipelines, including effectiveness of ILI tools and other in-the-bell hole examination methods to detect SCC."

The scope statement was broken down into components of Understanding Stress Corrosion Cracking (SCC) in Pipelines (Chapter 4); Prevention of an SCC Problem (Chapter 5); Detection of SCC (Chapter 6); and Mitigation of SCC (Chapter 7).

This chapter summarizes the current state of knowledge for understanding how to prevent SCC, or perhaps more directly, how to prevent an SCC problem in pipelines.

5.2 Coatings

Inadequate coating performance is a major contributing factor for increased SCC susceptibility of an underground pipeline. The majority of high-pH SCC failures have been associated with bituminous coatings (coal tar or asphalt), while the near neutral-pH SCC failures have occurred most frequently on tape-coated pipelines. The surface preparation conditions, degradation modes, and electrical behavior of these coatings are responsible for the type and prevalence of SCC on pipelines. The effectiveness of a coating system in preventing SCC is related to three factors:

1. the resistance of a coating to disbondment,
2. the ability to pass CP current should the coating fail, and
3. the type of surface preparation used with the coating.

Requirements for SCC-resistant coatings can be established, based on these factors, as described below.

In the early 1990s, Pipeline Research Committee International (PRCI) funded a three-year research program to investigate the role of these three factors on resistance to high-pH SCC of common pipeline coatings (Beavers 1992; Beavers, et. al 1993a, 1993b). The ability of a coating to resist disbonding is a primary performance property of coatings and affects all forms of external pipeline corrosion. An intact coating that prevents contact of electrolyte with the steel surface will mitigate all integrity threats associated with external corrosion, including SCC. Coatings with good adhesion properties are generally resistant to the mechanical action of soils from wet/dry cycles and freeze/thaw cycles. They also are better able to resist the effects of water transmission and cathodic disbondment (CEPA 1997).

The ability of a coating to pass CP current, should it fail, is the inverse of shielding the CP current beneath a disbonded coating. Shielding is of special significance to the occurrence of both forms of SCC. Near neutral-pH SCC is more frequently found with coatings that shield CP current, such as tape coatings. In the case of high-pH SCC, the potential range for SCC lies between the native potential of steel in most soils and adequate CP of -850 mV copper sulfate electrode (CSE) (Berry 1974). Partial shielding by disbonded coatings can cause the pipe to lie in the potential range for cracking, even for pipelines apparently protected by CP.

In the PRCI program on coatings, coating impedance tests were performed to evaluate the ability of the different coatings to conduct CP current in the absence of actual holidays (Beavers 1992). Single-layer FBE coatings were found to conduct CP current in the absence of holidays, whereas polyethylene tape coating completely shielded the CP. Coaltar enamel coating exhibited intermediate behavior, allowing CP current to flow after long exposure periods (greater than one year). In the case of the FBE coating, conduction of the CP current was associated with the formation of coating blisters containing a high-pH (greater than 12) electrolyte. This pH is higher than the pH range for high-pH cracking such that this form of cracking is unlikely to occur even if the potential range were appropriate for cracking. Liquid urethanes and epoxies were not tested in the study, but similar behavior would be expected with these and other coatings that are water-permeable.

The relationship between surface condition of a linepipe steel and SCC has been the subject of several previous PRCI laboratory research programs (Barlo and Fessler 1981; Beavers 1992; Beavers et. al 1993a). The research indicates that grit-blasted surfaces are generally more resistant to high-pH SCC initiation than mill-scaled surfaces, primarily because grit blasting imparts a compressive residual stress in the pipe surface. The majority of single-layer FBE coatings are applied in coating mills over grit-blasted surfaces prepared to a white (NACE No. 1/SSPC-SP 5) or near-white (NACE No. 2/SSPC-SP 10) surface finish. The older bituminous coatings were frequently applied over the ditch on mill-scaled surfaces. More recently, bituminous coatings have been applied in the mill using a commercial blast cleaning (NACE No. 3/SSPC-SP 6). The surface preparation necessary for FBE coating was found to be highly resistant to high-pH SCC, in comparison with mill-scaled surfaces. On the other hand, the lower quality grit blast that is commonly used with plant-applied bituminous coatings actually decreased SCC resistance compared to that found with a mill-scaled surface, primarily by creating stress raisers at imbedded mill scale particles. Clean grit-blasted surfaces are also readily polarized in the presence of CP such that the potential is not likely to remain in the cracking range for long periods of time. While the above research was performed on initiation of high-pH SCC, it is possible that the beneficial effects of grit blasting extend to near neutral-pH SCC initiation as well.

In summary, field experience and related research demonstrate that prudent coating selection and proper application are effective tools to prevent SCC of underground pipelines. The CEPA member companies have recommended that the following coatings be consider for new construction based on SCC performance (CEPA 1997):

- Fusion Bonded Epoxy (FBE)
- Liquid Epoxy
- Urethane
- Extruded Polyethylene

- Multi-Layer or Composite Coatings

FBE, liquid epoxies, and urethane coatings meet all three requirements of an effective coating; they have high adhesive strength and are resistant to disbondment, they conduct CP current should they fail, and they are typically applied over a white or near white grit-blasted surface. Extruded polyethylene coatings meet the first and third requirements, but will shield CP current should damage occur. Furthermore, the type of coating used on the field joints frequently limits the performance of extruded polyethylene coated pipelines. Multilayer or composite coatings typically consist of an FBE inner layer and a polyolefin outer layer with an adhesive between the two layers. These new coatings are promising from the standpoint of resistance to disbondment, mechanical damage, and soil stresses, but the polyolefin outer layer will shield CP current should disbondment occur. Additional field experience is needed to establish the performance of these coatings.

Tape coatings and bituminous coatings have been shown to be more susceptible to SCC than the above coatings and should be used only with careful consideration of all of the factors affecting SCC susceptibility.

Regardless of the coating selected, the pipe surface should be prepared to a white (NACE No. 1/SSPC-SP 5) or near white (NACE No. 2/SSPC-SP 10) finish to impart sufficient residual compressive stresses to prevent SCC initiation. A lower quality commercial blast (NACE No. 3/SSPC-SP 6) should not be used under any circumstances.

5.3 Pipe Steel Selection

Field studies of high-pH SCC have not identified any unique characteristics of failed pipe (Wenk 1974). At the time of the study, most of the failures occurred in API 5L X-52 (ASTM Grade 358) line pipe steel, but this was the most common grade for larger diameter line pipe. The chemical compositions of the failed pipes were typical for the vintage and grade, and there were no obvious unique metallurgical characteristics associated with the failures. Similarly, in laboratory studies, no correlation has been found between the concentration of impurities in the steel, such as phosphorus and sulfur, and high-pH SCC susceptibility (Beavers and Parkins 1986). It has been shown that major alloy additions, such as chromium, nickel, molybdenum, and titanium, to steel in amounts of between 2 to 6 percent decrease SCC susceptibility (Parkins et. al 1981) but such additions are impractical because of cost considerations. Resistance to high-pH SCC increases with increasing carbon content (Parkins et. al 1981), but high-carbon steels are difficult to weld.

Data from pipeline failures caused by near neutral-pH SCC showed that this form of SCC has developed on a wide variety of pipe. Pipe failures have occurred on grades varied from API 5L X35 (ASTM Grade 241) to API 5L X65 (ASTM Grade 448) (NEB 1996). Both ERW and double submerged arc weld (DSAW) pipe have been involved in SCC-related failures. The CEPA funded a research program to determine whether the initiation of near neutral-pH SCC could be correlated with pipe metallurgical factors (Beavers et. al 2000). Fourteen pipe samples from susceptible pipe joints, ranging in diameter from 8 to 42 inches (200 to 1,067 mm) and API 5L X-52 to X-70 (ASTM Grades 358 to 483), were examined. The results of this study indicate a strong correlation between residual stress and the presence of near neutral-pH SCC colonies. No statistically significant correlation was found between the occurrence of SCC on the pipes and the other factors evaluated in the study: chemical composition, cyclic stress-strain behavior, inclusion properties (number, area, and composition), and local galvanic behavior. Surkov et al (Surkov, 1994) observed a relationship between susceptibility to near neutral-pH SCC and the length of nonmetallic inclusions in the steel.

One gas transmission company developed an SCC prediction model via a statistical analysis of an extensive database containing information on the construction and operation of the pipeline (Beavers and Harper 2004). Three parameters were found to be key predictive variables in the model; pipe manufacturer, coating type, and soil type. Fourteen pipe manufacturers were used in the construction of the pipeline, and the relative probability of finding near neutral-pH SCC varied by more than a factor of 20 depending on the pipe manufacturer. While the cause of this large difference was not established, it is possible that residual stresses introduced by pipe manufacture played a role, given the other available field and laboratory data.

There is a growing body of evidence to suggest that tensile residual stresses in the pipe play a significant role in SCC and that cracking can be minimized or prevented by reducing these stresses during manufacturing, as well as during installation and operation. The laboratory and field data do not provide any clear guidance with respect to chemistry or other aspects of the pipe manufacturing process and prevention of SCC. The trend in steel manufacturing is to improve the mechanical properties by micro alloying and controlled rolling, and by decreasing the carbon content. Limited research results suggest that these newer steels may not necessarily have greater susceptibility to high-pH SCC even though they have higher yield strengths and lower carbon contents. These results indicate that a more important variable for assessing initiation of SCC is the ratio of the applied stress to the actual yield strength (Parkins et. al 1981).

Higher strength steels may be more susceptible to near neutral-pH SCC given the possible role of hydrogen embrittlement in the cracking process. It is known that if a higher strength pipe is substituted for a lower strength pipe with the same diameter and operating pressure, the critical flaw tolerance of the pipe decreases due to the reduced wall thickness.

5.4 Design Operating Pressure

The predominant longitudinal orientation of both forms of SCC on underground pipelines demonstrates the importance of the hoop stress produced by the internal pressurization on the cracking process. Laboratory studies of initiation of high-pH SCC have shown that stress corrosion cracks initiate above an applied stress level referred to as the threshold stress (Barlo 1979), reported as a percent of the yield stress. This threshold stress is affected by the surface condition, the potency of the environment and cyclic stresses.

In the NEB inquiry (NEB 1996), significant SCC was not reported by Canadian pipeline operators in Class 2 and 3 pipeline locations. CEPA suggested that the standard wall pipe used in Class 2 and 3 locations is less susceptible to SCC because it operates at lower stress levels than pipe in Class 1 locations. The majority of SCC failures on Canadian pipelines have been the near neutral-pH form of cracking. In Class 1 locations, the extent and severity of SCC was found to decrease with decreasing stress, due to the internal operating pressure. On TCPL Line 2, the number of SCC colonies decreased from 0.014 to 0.0005/m (3.56×10^{-4}/in. to 1.27×10^{-5}/in.) inspected as the stress dropped from 75 to 67 percent SMYS. A similar trend was found for crack depth.

Based on laboratory and field data, it is reasonable to conclude that reducing the design operating stress as a percentage of the yield stress can reduce the likelihood of initiation of stress corrosion cracks. Reducing the operating stress has the added advantages of increasing the critical flaw size, as well as increasing the critical leak/rupture length.

5.5 Design Operating Temperature

Fessler evaluated the effect of temperature on high-pH SCC (Fessler 1979). Field data available at the time along with laboratory research on the subject were summarized. Service failures were reported at temperatures as low as 13°C (55°F), but 90 percent of the service and hydrostatic test failures occurred within 16 km (10 miles) downstream from the compressor stations, where the highest temperatures were present. This behavior is associated with a decrease in the width of the potential range for cracking, coupled with a decrease in the maximum cracking velocity with decreasing temperature.

Laboratory data and field experience indicate that there is less temperature dependence for near neutral-pH SCC than for high-pH SCC. Delanty and O'Beirne (1991) reported that 50 percent of near neutral-pH SCC failures on TCPL Line 2 occurred within 10 miles downstream of compressor stations versus 90 percent for high-pH SCC. Because the spacing between compressor stations is typically 100 km (62 miles) on the TCPL System, 16 km (10 miles) correspond to less than about 15 percent of the total length. This behavior suggests that temperature or some other factor affects the occurrence of near neutral-pH SCC, just not to the extent that that it occurs with high-pH SCC. The higher temperature promotes more extensive and rapid coating disbondment, for example. It is also possible that the higher stresses or larger stress fluctuations near the compressor station produce more frequent near neutral-pH SCC failures.

Based on laboratory and field data, it is reasonable to conclude that reducing the design temperature of a pipeline can reduce the likelihood of stress corrosion crack initiation by several processes, including reduced crack velocities, reduced probability of crack initiation (high-pH SCC) and improved coating performance. One method of temperature control that has been implemented by some operators is the installation of cooling towers.

5.6 Construction

Proper construction practices, such as minimizing fit-up stresses and avoiding dents and mechanical damage to the pipe, can reduce the likelihood of SCC initiation. The surface preparation and field-applied coatings for girth welds should be selected and applied with the same care as used in the shop-applied coating. Damage to the coating should be avoided and repaired when it does occur, to avoid holidays, which can act as initiation sites for disbondment.

5.7 Operations and Maintenance

5.7.1 Cathodic Protection

Cathodic protection (CP) is closely related to the high-pH cracking process. The CP current collecting on the pipe surface at disbondments, in conjunction with dissolved CO_2 in the groundwater, generates the high-pH SCC environment. CP can also place the pipe-to-soil potential in the potential range for cracking. The potential range for cracking generally lies between the native potential of underground pipelines and the potential associated with adequate protection (-850 mV CSE) (Parkins 1974; Fessler 1979). Based on field pH measurements of electrolytes associated with near neutral-pH SCC colonies, it has been concluded that this form of SCC occurs in the absence of significant CP either because of the presence of a shielding coating or high-resistivity soils that limit CP current to the pipe surface (Delanty, 1991).

Based on the available laboratory and field data, it can be concluded that the polarized pipe-to-soil potential of pipeline segments that are potentially susceptible to high-pH SCC should be maintained above (more negative than) –850 mV CCS. Potentially susceptible segments can be assessed using ASME B31.8S Appendix A3 for gas pipelines, which considers historical information, coating type, operating temperature, age, operating stress, and distance downstream from the compressor station. For liquid pipelines, the distance downstream of the pump station can be used in the ASME assessment (NACE 2004). The other CP criteria (100mV polarization or 850 mV with CP applied) should not be used on potentially susceptible segments. Consideration should be given to seasonal fluctuations in the potential to minimize the likelihood that the pipe falls into the cracking range on a seasonal basis.

Near neutral-pH SCC is most prevalent on pipelines with shielding coatings (e.g. tape) and has occurred where the pipeline is apparently protected based on CP information. Nevertheless, it is worthwhile to maintain adequate protection to avoid SCC and corrosion at or near holidays. Effective CP also will minimize the occurrence of near neutral-pH SCC with non-shielding coatings.

5.7.2 Recoating Existing Pipelines

The factors that affect SCC performance of a coating system, described above, are applicable to recoating of existing pipelines as well as new construction. These are:

1. the resistance of a coating to adhesion/disbondment,
2. the ability to pass CP current should the coating fail, and
3. the type of surface preparation used with the coating.

As described above, it is imperative that the surface is prepared to a white or near white finish prior to coating application and that the coating applied have desirable performance characteristics, such as good adhesion, resistance to disbondment and the ability to conduct CP current should the coating fail.

There are several other factors that must be considered in the selection of field coatings. These include the ambient weather and environmental conditions required for application, compatibility with existing coatings, equipment requirements, and access to the field site and pipe. Further discussion of these issues is provided in the CEPA SCC Recommended Practice (CEPA 1997).

5.7.3 Other Operational Considerations

Reducing cyclic pressure fluctuations can minimize the occurrence of both forms of SCC. These fluctuations reduce the threshold stress for the initiation of cracks and increase the propagation rate of SCC (Parkins and Greenwell 1977; Beavers and Jaske 1998). Furthermore, final failure of SCC colonies can occur by pressure cycle fatigue for large deep flaws or large pressure cycles.

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6 Detection of SCC

6.1 Scope Statement

"Compile a report summarizing the history of SCC on pipelines, explaining the causes and factors contributing to SCC initiation and growth, and discussing methods for prevention, detection and mitigation of SCC on pipelines, including effectiveness of ILI tools and other in-the-bell hole examination methods to detect SCC."

The scope statement was broken down into components of Understanding Stress Corrosion Cracking (SCC) in Pipelines (Chapter 4); Prevention of an SCC Problem (Chapter 5); Detection of SCC (Chapter 6); and Mitigation of SCC (Chapter 7).

This chapter summarizes the current state of knowledge of understanding how to detect SCC, or perhaps more directly, how to detect a SCC problem in pipelines.

6.2 Detection Methods

6.2.1 Hydrostatic Testing

Hydrostatic testing has been used to locate SCC in pipelines and, when properly implemented, assures that critical defects existing at the time of the test are identified. Because of its straightforward approach and interpretation, it is the mainstay of all regulatory codes, and is currently generally accepted to be the best available technique to ensure the integrity of the pipe at the time of testing. Stress corrosion cracks can result in overload failures during a hydrostatic test. Hydrostatic testing failures occur when stress corrosion cracks reduce the load carrying capability of a pipeline sufficiently to allow a fracture toughness dependent or plastic collapse rupture. Hydrostatic testing ruptures do not propagate a significant distance because water is essentially non-compressible and, therefore, the stress level drops rapidly after a rupture occurs.

The U.S. federal safety regulations (49 CFR 192 Subpart J and 49 CFR 195 Subpart E) require that pipelines that operate at pressures at or above 30% of specified minimum yield strength (SMYS) and are used to transport natural gas or hazardous liquids be pressure tested at a pressure equal to 125% of the maximum allowable operating pressure (MAOP) in the case of gas pipelines and 125% of the maximum operating pressure (MOP) in the case of liquid pipelines, following construction or replacement. Water as a test medium is required for the pressure test except in cases where the pipeline is remote to buildings intended for human occupancy. In the latter case, air or inert gas can be used for testing. For pipelines operating at an MAOP of 72% of SMYS, a minimum test pressure of 90% of the SMYS will achieve the minimum requirements. The federal regulations require that this test pressure be maintained for 8 hours.

Periodic hydrostatic testing also is a common method used to ensure the integrity of operating pipelines that contain growing defects, such as general or pitting corrosion, fatigue, corrosion fatigue, or stress corrosion cracking. The testing protocol varies for different pipeline operators, depending on details of the system, but most meet the minimum federal requirements for new construction. Typically, a desired pressure range is established, with the minimum pressure selected to ensure integrity and the maximum test pressure designed to minimize failure of non-injurious features, such as stable weld flaws, in the pipeline. Factors considered in the selection of a minimum pressure include the estimated population of defects in the pipeline, the estimated growth rate of these defects, and the MAOP of the pipeline. If there are a large number of slow-growing defects and the MAOP of the pipeline is relatively low, it may be desirable to establish a low minimum test pressure to avoid a large number of hydrostatic test failures. On the other hand, a higher minimum test pressure is needed to avoid frequent retesting for fast-growing defects and high operating pressures.

Some pipeline companies use a short duration high-pressure spike (e.g., 100 to 110% of SMYS for 1 hour) to remove long flaws capable of producing a rupture, followed by a long duration low-pressure test (e.g., 90% of SMYS for 24 hours) to locate leaks in the pipeline (Brongers 2000). The purpose of pressurizing to a high level for one hour is to remove potentially deleterious defects, while the purpose of holding at a reduced pressure for a long period is to avoid pressure reversals. A pressure reversal is where a defect survives hydrostatic testing at a high pressure only to subsequently fail at a lower pressure upon repressurization. PRCI studies (Kiefner 1986) have shown that a rupture at MAOP, as a result of a pressure reversal, is highly unlikely (<1/10,000) when the test pressure is at least 1.25 times the MAOP. If MAOP equals 72% of SMYS, this implies a minimum test pressure of 90% of SMYS. Furthermore, experimental fracture mechanics studies of specimens from ERW X52 and X65 steel pipe showed that the amount of ductile crack tearing (crack advance) at loads up to 110% of SMYS is less than 25% of the typical amount of SCC growth expected in one year. Thus, this typical test procedure is not likely to cause significant ductile crack tearing or pressure reversals (Brongers 2000).

6.2.1.1 Benefits

Because of its straightforward approach and interpretation, hydrostatic testing is the mainstay of all regulatory codes, and is currently generally accepted to be the best available technique to ensure the integrity of the pipe at the time of testing. It will remove all axial defects, regardless of geometry, that have critical dimensions at the test pressure. Hydrostatic testing also might open up incipient leaks so that they can be detected. In the case of in-line inspection and other integrity programs, such as SCCDA, there is a finite probability that a near critical defect will be missed by the assessment method. In the case of crack-like defects, such as fatigue cracks and stress corrosion cracks, hydrostatic testing also will blunt and impart a compressive residual stress at the crack tip of sub-critical defects that remain in the pipeline following testing. The blunting and compressive residual stresses will inhibit subsequent fatigue or SCC crack growth (Hohl 1999, Beavers 1996).

6.2.1.2 Limitations

Following a hydrostatic test, sub-critical cracks will still remain in the pipeline and, potentially, may be just smaller than the size that would have failed in the hydrostatic test. As described above, hydrostatic testing can cause tearing of these sub-critical flaws leading to a pressure reversal, where the pipeline fails in service or at a lower pressure in a subsequent hydrostatic test. Typically, the amount of tearing and the magnitude of these pressure reversals are small but, in rare circumstances, large pressure reversals exceeding 100 psig can occur. At operating pressure, these remaining sub-critical cracks also may continue to grow by SCC, fatigue or corrosion fatigue. Therefore, hydrostatic retesting, or other detection methods, must be performed on a pipeline containing growing defects to ensure pipeline integrity.

For older pipelines and those containing ERW welds, high-pressure tests (e.g., above 100% of SMYS) may not be practicable because the testing could potentially fail large numbers of non-injurious weld flaws. With lower pressure tests, the hydrostatic retest period may be short enough to make hydrostatic retesting impracticable. Figure 6-1 shows the remaining life as a function of test pressure for a 3-inch long flaw in a 12.75-inch diameter, 0.213-inch wall thickness, API 5LX60 pipeline operating at 72% of SMYS (1440 psig), and an assumed flaw growth rate of 0.012 inches per year (0.3 mm/y). This is a typical growth rate for a growing SCC defect. In this example, the retest frequency would have to be approximately 3 years for a hydrostatic test at 90% of SMYS (1800 psig) to avoid further failures of the pipeline.

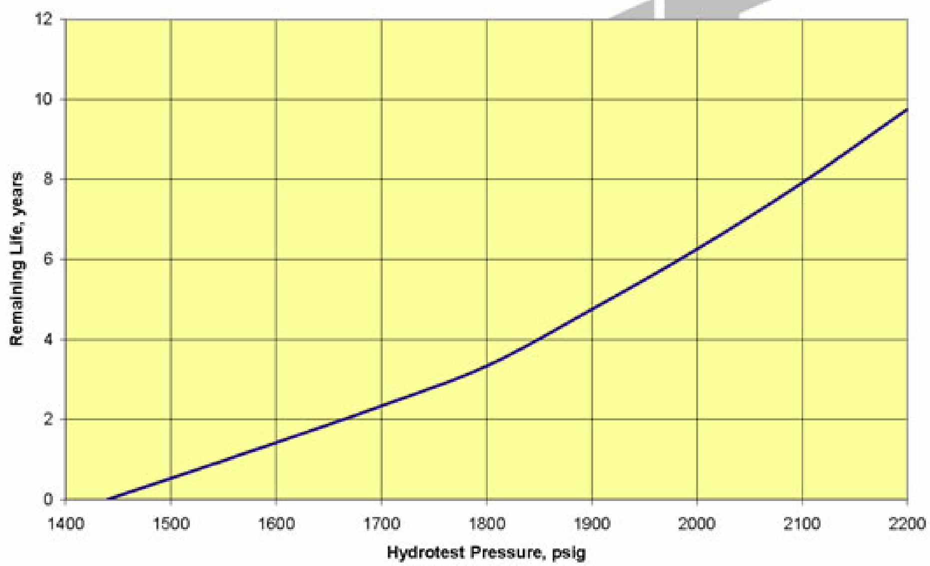

Figure 6-1 Remaining Life as a Function of Hydrostatic Test Pressure (Using CorLAS™)

Hydrostatic testing is not effective against circumferential flaws because the maximum axial stress produced by internal pressurization is less than about half the circumferential stress. While hydrostatic testing is capable of locating leaks, it is not effective in removing short flaws that ultimately will produce leaks. Leaks can occur shortly after a hydrostatically tested line has been returned to service.

Additional problems exist with the technique. Hydrostatic testing is very expensive for the very few flaws that are removed, since the pipeline must be taken out of service. ILI is much more effective